OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **June 18, 2018**

TO: PF Phillip Fielder, P.E., Permits and Engineering Group Manager

THROUGH: PM Phil Martin, P.E., Engineering Manager, Existing Source Section

THROUGH: Amalia Talty, P.E., Existing Source Permit Section

FROM: Eric L. Milligan, P.E., Engineering Section

SUBJECT: Evaluation of Permit Application No. **2015-1968-C (M-2) PSD**
Western Farmers Electric Cooperative
Anadarko Power Plant (SIC 4911/NAICS 22112)
Facility ID: 1699
NW/4 of Section 14, T7N, R10W, Caddo County
Latitude: 35.08293°N; Longitude: 98.23380°W
Located 1 mile north of SH 62 and 7th Street in Anadarko, Oklahoma

SECTION I. INTRODUCTION

Western Farmers Electric Cooperative (WFEC) has requested a modification of the original prevention of significant deterioration (PSD) construction permit (Permit No. 2000-273-C (PSD)) for the installation of the two natural gas-fired simple cycle peaking combustion turbines (AN-UNIT7 and AN-UNIT8) at the facility which was previously named GENCO Anadarko Power Plant which is now part of the WFEC Anadarko Power Plant. The modification would remove the 0.09 lb NO_X/MMBTU emission limit. Only issues related to the 0.09 lb NO_X/MMBTU emission limit are revised in this permit. This modification will not increase emissions from the facility nor change the BACT determination. The PSD evaluation to include best available control technology (BACT) and air dispersion modeling are incorporated into this permit as they existed in Permit No. 2000-273-C (PSD) which was issued on November 30, 2000. The facility is currently operating as authorized by Permit No. 2015-1968-TVR3, issued February 6, 2018.

Based on information in the original permit application, the 0.09 lb NO_X/MMBTU emission limit established in the original PSD permit is equivalent to the 41 lb/hr and 25 ppmdv NO_2 at 15% O_2 emission limits at a heat input of 457.95 MMBTUH, high heating value (HHV), at 20 °F. WFEC believes that the 0.09 lb NO_X/MMBTU emission limit is overly burdensome and unnecessary for demonstrating compliance with the underlying applicable requirement of OAC 252:100-33 (0.2 lb/MMBTU). The AQD agrees with the assessment and has removed the 0.09 lb NO_X/MMBTU emission limit from the permit.

SECTION II. FACILITY DESCRIPTION

The facility generates wholesale electricity which is transmitted over WFEC's electrical distribution system. The electricity is sold in rural areas of approximately 3/4 of the state of Oklahoma. The facility currently consists of three (3) natural gas-fired high pressure boilers (AN-UNIT1R, AN-UNIT2R, and AN-UNIT3), three (3) natural gas-fired combined cycle gas turbines (AN-UNIT4, AN-UNIT5, and AN-UNIT6), five (5) natural gas-fired simple cycle peaking combustion turbines (AN-UNIT7, AN-UNIT8, AN-UNIT9, AN-UNIT10 and AN-UNIT11), two (2) diesel-fired engines (ENG-1, and Emerg. Gen.) and other sources which are considered insignificant or trivial. AN-UNIT1R, AN-UNIT2R, and AN-UNIT3 are backup units that only operate when it is feasible, such as during peak demand. This permit only addresses two of the natural gas-fired simple cycle peaking combustion turbines (AN-UNIT7 and AN-UNIT8) and the diesel-fired emergency black start generator (Emerg. Gen.) which were authorized by Permit No. 2000-273-C (PSD).

AN-UNIT7 and AN-UNIT8, are capable of producing 47,000 kW each with quick start capability and will combust approximately 452 MMBTUH of natural gas each. The two (2) turbines are designed as peaking units, with a combined operation of 8,000 hours per year.

There is only one operating scenario for the facility with the turbines fueled with commercial-grade natural gas. Emission units (EUs) are arranged into Emission Unit Groups (EUGs) in the "Equipment" section.

SECTION III. EQUIPMENT

EUG 4 Internal Combustion Engine

EU	Make/Model	hp	Serial #	Const. Date
Emerg. Gen	Kohler/600 ROZD-4	910	0655525	2000

EUG 6 Simple Cycle Combustion Turbines

EU	Manufacturer	MMBTUH[1]	MW	Serial #	Const. Date
AN-UNIT7	General Electric	451.7	47	191264	2001
AN-UNIT8	General Electric	451.7	47	191246	2001

[1] - HHV; Maximum Heat Input @ 59 °F &100% Load.

Stack Parameters

EU	Height (feet)	Diameter (feet)	Flow (ACFM)	Temperature (°F)
AN-UNIT7	45	9.0	538,202	790
AN-UNIT8	45	9.0	538,202	790

SECTION IV. EMISSIONS

AN-UNIT7 & AN-UNIT8

Potential emissions from EU AN-UNIT7 and AN-UNIT8 are based on a 12-month rolling total of the combined operation of both units for 8,000 hours of operation, the maximum rated heat input, and the following emission factors:

	NO_X	CO	VOC	$PM_{10}/PM_{2.5}$	SO_2
Factor	lb/MMBTU[1]	lb/MMBTU[1]	lb/MMBTU[1]	lb/MMBTU[1]	lb/MMBTU[2]
lb/hr	0.0895	0.2675	0.0047	0.0066	0.0034
TPY	0.0882	0.0504	0.0031	0.0066	0.0034

1 - Manufacturer's data;
lb/hr factors based on worst-case: 20 °F @ 100% Load (458 MMBTUH-HHV).
NO_X: 25 ppmvd @ 15% O_2.
CO: 125 ppmvd @ 15%O_2.
VOC: 5 ppmvd @ 15% O_2 ; 20% of HC.
CO and VOC are 2.5 times the manufacturer's data as suggested by the manufacturer.
TPY factors based on average: 59 °F @ 100% Load (452 MMBTUH-HHV);
NO_X: 25 ppmvd @ 15% O_2.
CO: 23 ppmvd @ 15%O_2.
VOC: 1.5 ppmvd @ 15% O_2; 20% of HC.

2 - AP-42 (4/2000), Section 3.1, Table 3.1-2a default value.

Emerg. Gen

Potential emissions from EU Emerg Gen are based on 500 hours of operation per year, the maximum engine rating, and the following emission factors:

	NO_X	CO	VOC	$PM_{10}/PM_{2.5}$	SO_2
EU	lb/MMBTU	lb/MMBTU	lb/MMBTU	lb/MMBTU	lb/MMBTU[2]
Emerg. Gen[1]	1.4363	0.2305	0.0435	0.0777	0.0015

1 - Manufacturer's data based on original standby rating: 765-bhp, 37.7 gallons/hour, and 0.137 MMBTU/gallon.

2 - SO_2 emissions based on AP-42 (10/1996), Section 3.4, Table 3.4-1, and a fuel sulfur content of 15 ppm by weight (Ultra Low Sulfur Diesel).

Permitted Emissions

	NO_X		CO		VOC		PM_{10}		SO_2	
EU	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
AN-UNIT7	41.0	159.3	122.5	91.0	2.1	1.2	3.0	12.0	1.6	6.2
AN-UNIT8	41.0		122.5		2.1		3.0		1.6	
Emerg. Gen	7.4	1.9	1.2	0.3	0.2	0.1	0.4	0.1	0.1	0.1
Totals	**89.4**	**161.1**	**246.2**	**91.3**	**4.4**	**1.3**	**6.4**	**12.1**	**3.3**	**6.3**

The turbines and engine have emissions of HAP, the most significant being formaldehyde. Emissions of formaldehyde are based on the following: Turbines - AP-42 (4/00), Section 3.1 for standard operation and Section 3.1 reference data for less than 25% load; and Engine - AP-42

(10/96), Section 3.3. A specific condition limiting emissions of formaldehyde to less than 10 TPY is established.

Formaldehyde Emissions from the Turbines and Engine

		Rating	Factors	Max Emissions		Actuals[c]
Sources	**# Units**	**MMBTUH**	**lb/MMBTU**	**lb/hr**	**TPY**	**TPY**
GE Simple Cycle Turbines[a]	2	452.0	0.00071 (normal)	0.642	1.530	0.90
		106.25	0.0131 (SU/SD)	2.784		
Kohler Engine[b]	1	5.17	0.0012	0.002	0.001	0.00
Totals				**20.357**	**5.059**	**4.55**

a - Units are limited to annual operation of 8,000 hours per year combined. SU/SD. Startup operations are based on 200 hours per year combined.

b - Unit is limited to 100 hours of operation for testing, the unit may be used for unlimited periods in the event of an emergency.

c - Based on 2016 emission inventory data.

SECTION VII. PSD EVALUATION / SCOPE OF REVIEW (From Permit No. 2000-273-C (PSD))

The existing facility is a PSD major source, therefore, modification must be reviewed to determine if any PSD significance level will be exceeded. The following table lists the total emissions from the modification compared to the PSD significance levels. Since NO_X emissions exceed the PSD significance level, full PSD review is required for NO_X. The three year contemporaneous emissions are not listed here since the facility is not netting out, however, these emissions are included and described in the modeling section.

Significance Levels Comparisons (TPY At Maximum Operation)

Pollutant	Emissions	PSD Significance Level	PSD Review Required
NO_X	161.14	40	yes
CO	91.30	100	no
VOC	1.26	40	no
PM_{10}	12.24	15	no
SO_2	1.27	40	no
Lead	0.02	0.6	no
H_2SO_4	0.18	7	no

The project is also subject to NSPS Subpart GG for combustion turbines. Numerous Oklahoma air quality rules affect the new turbines and emergency generator as fuel-burning equipment; rules including Subchapters 19, 25, 31, 33, and 37. Pollutants emitted in minor quantities were evaluated for all pollutant-specific rules, regulations and guidelines. Since HAP emissions are calculated below the 10/25 TPY threshold, no case-by-case MACT review is required.

Full PSD review of emissions consists of the following:

- determination of best available control technology (BACT)
- evaluation of existing air quality and determination of monitoring requirements
- evaluation of PSD increment consumption
- analysis of compliance with National Ambient Air Quality Standards (NAAQS)
- evaluation of source-related impacts on growth, soils, vegetation, visibility
- evaluation of Class I area impacts

SECTION VIII. BACT REVIEW
(From Permit No. 2000-273-C (PSD))

The requirement to conduct a BACT analysis is set forth in the PSD regulations [OAC 252:100-8-30 et seq.]. BACT is generally defined in the PSD regulations as the following:

> *"... the control technology to be applied for a major source or modification is the best that is available as determined by the Executive Director on a case-by-case basis taking into account energy, environmental, costs and economic impacts of alternate control systems."*

The BACT review follows the "top-down" methodology. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. Presented on the following page are the five basic steps of a top-down BACT review procedure as identified by the U.S. EPA in the March 15, 1990, Draft BACT Guidelines:

Step 1. Identify all control technologies
Step 2. Eliminate technically infeasible options
Step 3. Rank remaining control technologies by control effectiveness
Step 4. Evaluate most effective controls and document results
Step 5. Select BACT

The EPA has consistently interpreted the statutory and regulatory BACT definition as containing two core requirements that the agency believes must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies, (i.e., those which provide the "maximum degree of emissions reduction"). Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of energy, environmental, and economic impacts.

If the source is subject to a New Source Performance Standard (NSPS), the minimum control efficiency to be considered in a BACT analysis must result in an emission rate less than or equal to the NSPS emission rate. In other words, the applicable NSPS represents the maximum allowable emission limit from an emission source.

The BACT requirements only apply to the pollutants that are subject to PSD review and the emission units that are newly installed or physically modified. The GENCO peaking units are new emission units with potential NO_X emissions above PSD significance levels and, therefore, subject to BACT review.

a) Control Technology Identification

NO_X reduction can be accomplished by two general methodologies, combustion control methods and post-combustion control techniques. Combustion control techniques incorporate fuel or air staging that affect the stoichiometry and kinetics of NO_X formation or introduce inerts (combustion products, for example) that limit initial NO_X formation, or both. Post-combustion technologies chemically reduce NO_X to molecular nitrogen (N_2) with or without the use of a catalyst.

Specific NO_x control technologies are identified from the U.S. EPA control technology database search, technical literature, and control equipment vendor information and by using process knowledge and engineering experience. Potentially applicable control options and typical control ranges for NO_X were identified and summarized below.

Control Technology	Typical Emission Levels
SCONOx™	2-5 ppm
XONON flameless combustion	3-5 ppm
Selective catalytic reduction (SCR)	5-9 ppm
Selective non-catalytic reduction (SNCR)	9-25 ppm
Non-selective catalytic reduction (NSCR)	9-25 ppm
Dry low NO_X combustor	9-25 ppm
Water or steam injection	25-42 ppm

A general overview of each of these control technologies is provided in the following paragraphs. Technical feasibility, environmental impacts, and economical feasibility are discussed in the subsequent sections.

b) Control Technology Overview

<u>SCONOx™</u>

SCONOx™ is an emerging technology which offers the promise of reducing combined-cycle NO_X emissions to values in the range of 2 to 3.5 ppm. EPA issued a finding on July 2, 1997, that

SCONOx™ has been demonstrated in practice as LAER at a 23 MW facility in California and those emissions have been demonstrated at 2.5 ppm.

According to literature the system uses an oxidation/absorption/regeneration cycle across a catalyst bed to achieve back end reductions of NO_X. Unlike SCR, the system does not require ammonia as a reagent and involves parallel catalyst beds that are alternately taken off-line for regeneration through means of mechanical dampers.

The SCONOx™ catalyst works by simultaneously oxidizing CO to CO_2, NO to NO_2, and then absorbing NO_2. The NO_2 is absorbed into a potassium carbonate catalyst coating as KNO_2 and KNO_3. When a catalyst module begins to become "loaded" with potassium nitrites and nitrates, it is taken off-line and isolated from the flue gas stream with mechanical dampers for regeneration.

Once the module has been isolated from the oxygen rich turbine exhaust, 4 percent hydrogen in an inert carrier gas of nitrogen or steam is introduced. An absence of oxygen is necessary to retain the reducing properties necessary for regeneration. It should be noted that four percent is about the lower flammability limit for hydrogen, so it is important that air seals around dampers do not leak. Hydrogen reacts with potassium nitrites and nitrates during regeneration to form H_2O and N_2 that is emitted from the stack.

Catalytic (Flameless) Combustion

Another emerging technology that is potentially capable of reducing combustion turbine NO_X emissions to 3 to 5 ppm is catalytic combustion. While several companies are reported to be working on this technology, it was first introduced commercially by Catalytica, Inc., and is being marketed under the name XONON™.

According to literature provided by Catalytica, XONON™ combustors have reduced combustion turbine NO_X emissions to as low as 3 ppm in laboratory and pilot tests. Unlike SCONOx™ or selective catalytic reduction (SCR), flameless combustion requires no down-stream clean up device, but rather prevents the formation of thermal NO_x during combustion of the fuel. This technique avoids the need for ammonia injection and avoids system efficiency losses due to catalyst back pressure. The XONON™ technology actually replaces the traditional diffusion or lean pre-mix combustion cans of the combustion turbine.

In a typical combustor, fuel and air are burned at flame temperatures that may approach 2,700°F. NO_X formation rate is exponential with flame temperature above 2,000°F, so thermal NO_X is formed within the combustors. The combustor exhaust is then diluted with cooling air to get the gas temperature below about 2,400°F, which is the upper temperature limit of the metal parts, which make up the power turbine. With the XONON™ system, a fuel/air mix is oxidized across several small catalyst beds to "burn" fuel at less than the flame temperature at which thermal NO_X formation begins. The XONON™ combustor does, however, utilize a partial flame downstream to complete the combustion process (burnout zone) and unavoidable small amounts of NO_X emissions are generated within this zone. Resulting emissions are being guaranteed by Catalytica at 5 ppm for certain applications and have been demonstrated as low as 3 ppm under test conditions. Like all catalysts, the XONON™ combustor catalyst performance can be expected to "age" with time.

Selective Catalytic Reduction (SCR)

SCR is a process that involves post-combustion removal of NO_X from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \qquad (1)$$
$$6NO + 4NH_3 \rightarrow 5N_2 + 6H_2O \qquad (2)$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (3)$$
$$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O \qquad (4)$$
$$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O \qquad (5)$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging, ammonia slip emissions, and design of the NH_3 injection system.

Three types of catalyst bed configurations have been successfully applied to commercial sources: the moving bed reactor, the parallel flow reactor, and the fixed bed reactor. The fixed bed reactor is applicable to sources with little or no particulate present in the flue gas, such as would be the case for the proposed combustion turbines. In this reactor design, the catalyst bed is oriented perpendicular to the flue gas flow and transport of the reactants to the active catalyst sites takes place through a combination of diffusion and convection.

Reduction catalysts are divided into two groups: platinum and base metal (primarily vanadium or titanium). Both groups exhibit advantages and disadvantages in terms of operating temperature, reducing agent/NO_x ratio, and optimum oxygen concentration. A disadvantage common to both platinum and base metal catalysts is the narrow range of temperatures in which the reactions will proceed. Platinum group catalysts have the advantage of requiring lower ignition temperature, but have been shown also to have a lower maximum operating temperature. Operating above the maximum temperature results in oxidation of NH_3 to either nitrogen oxides (thereby actually increasing NO_x emissions) or ammonium nitrate.

Optimum operating temperature for platinum catalyst system is in the range of 400° to 800°F and for the base metal catalyst system is in the range of 550° to 800°F. These catalysts deteriorate quickly when continuously operated at temperatures above this range or under thermal cycling which is commonly experienced by simple cycle peaking turbines. Operation at part load, and during start-up and shutdown yields non-optimum SCR temperature and decreased NO_X conversion efficiency. Since operation at less than design temperatures would neither effectively remove NO_X nor reduce ammonia, both would be emitted from the stack during off design catalyst temperatures. For this reason, automatic controls are used to reduce ammonia feed below set point temperature.

SCR manufacturers have developed zeolite-based catalyst systems that can handle high temperatures in the range of 790-1,100 °F and can withstand thermal load swings associated with peaking turbine installations. Typically, natural gas-fired simple-cycle turbine exhausts range in the higher temperature window of 850-1,000 °F, which is outside the range of most base metal catalysts, but theoretically within the range of operation for hot-SCR zeolite catalysts.

Selective Non-Catalytic Reduction (SNCR)

SNCR is based on the principal that ammonia or urea react with NO_X in the flue gas to form N_2 and H_2O. In practice, the technology has been applied in boilers by injecting ammonia into the high-temperature (e.g., 1,300°F - 2,000°F) region of the exhaust stream. Incorrect location of injection points, insufficient residence times and miscalibration of injection rates may result in excess emissions of ammonia (ammonia slip), a hazardous air pollutant (HAP). When successfully applied, however, SNCR has shown reductions in NO_x emissions from boilers of 35 to 60 percent.

Non-Selective Catalytic Reduction (NSCR)

This control technology uses a catalyst, generally a mixture of platinum and rhodium, to promote simultaneous conversion of NO_X, CO, and unburned hydrocarbon. NSCR is also referred to as "three-way conversion". NSCR requires the combustion process to be slightly fuel rich and within a temperature range of 650°F-1500°F. Under this condition, the CO reduces the NO_X to N_2 and CO_2. NSCR can achieve 80-95% NO_x conversion.

Dry Low NO_X Combustor

Although dry low NO_X (DLN) combustors designed by different manufacturers may vary, they all employ the strategies of fuel and air pre-mixing and staged combustion to minimize NO_X formation in combustion turbines. The combustors burn a lean, pre-mixed fuel and air mixture to avoid localized high temperature regions. Other techniques such as variable geometry, fuel staging, or combustion staging, are also incorporated in DLN combustor design. As a result, NO_X emissions are 60-80% lower than conventional combustors.

Water or Steam Injection

Sufficient water or steam can be injected into the flame zone of a turbine combustor to quench the peak flame temperature, thereby reducing the thermal NO_X formation. In general, water or steam injection can control NO_X emissions from conventional combustion turbines to a range of 25-42 ppm. This control technique may reduce turbine thermal efficiency and/or increase CO emissions.

c) Technical Feasibility

This section analyzes the technical feasibility of each of the control options described in the previous section.

SCONOx™

While SCONOx™ is a promising technology, it has yet to be fully demonstrated for commercial operation on a simple cycle combustion turbine. Further, it has not been demonstrated on any unit on a long-term basis.

The catalyst is subject to the same fouling or masking degradation that is experienced by any catalyst operating in a turbine exhaust stream. Trace impurities either ingested from ambient air or internal sources gradually accumulate on the surface of the catalyst, eventually masking or poisoning active catalyst sites over time. This is why catalyst performance is known to degrade or "age" over time. All catalysts begin life at their highest level of reactivity, resulting in very low emissions when first installed. Goal Line reports that they have had to take periodic outages to wash the catalyst; apparently SO_2 present in natural gas is sufficient to mask the active catalyst sites. Goal Line proposes to install an SO_2 "guard bed" called SCOSOx™ on future systems, but this component is unproven. As stated previously, catalyst aging is also experienced with conventional SCR catalysts; however, with these systems the operating experience exists to confidently predict catalyst life and catalyst replacement cost is far less than with SCONOx™.

Another area of concern is that the SCONOx™ process is dependent on numerous hot side dampers and gas seals that must cycle every 10 to 15 minutes. While further research and development (R&D) could be done during scale up in an effort to reduce the number of moving parts, the SCONOx™ system requires many mechanical linkages, activators, and damper seals which must operate reliably within a hostile flue gas environment. This, in combination with a lack of long-term demonstration generates concerns about the long-term availability of the system for this project.

XONON™ Catalytic (Flameless) Combustion

XONON™ is currently in development stage and does not represent a commercially available NOx control technology. While XONON™ is being sold as an alternative control technology for certain turbine models, it is currently not offered for the GE LM6000 turbines. At this time XONON™ is not a feasible control technology for the GENCO Site.

Selective Catalytic Reduction (SCR)

Conventional SCR is a proven (technically feasible) method of control for NOx emissions. The U.S. EPA identifies zeolite based SCR applications as most compatible with simple cycle turbines. However, a review of permit applications utilizing zeolite catalyst shows that the nascent technology has operational problems that would limit its technical feasibility:

> The June 1999 permit application for the ManChief facility in Colorado provides a narrative about simple-cycle high-temperature SCR applications which concludes that there are some discrepancies in the literature (Ozone Transport Assessment Group and Institute of Clean Air Companies - ICAC reports) about the instances of successful implementation of the technology for similar applications. This application identified only a single small turbine with SCR at a research facility.
>
> The U.S. EPA ACT reference, "NO_X Emissions From Stationary Combustion turbines" (EPA-453/R-93-007), indicated that zeolite based SCR applications were the most compatible with simple-cycle turbine operations. However, the reference also noted that there was only one SCR installation operating with a zeolite catalyst directly downstream of the turbine which mostly operated at 930 °F. The reference for this statement indicates that the turbine mentioned is the same small turbine mentioned in the ICAC paper.
>
> A permit application (Kendall Power facility in Plano, IL, dated February 1999) indicated that high-temperature SCR applications were fraught with operational problems, "...sustained operation at such high temperatures and widely fluctuating peaking turbine loads will likely result in the excessive wear and premature replacement of the zeolite catalyst."

A review of the RBLC database showed only a handful of projects that have proposed hot-SCR for similar turbine applications. The individual projects were further researched for status of hot-SCR implementation:

> Southern California Gas, Wheeler Ridge, CA - Simple-cycle natural gas-fired DLN equipped turbines each less than 10 MW. Hot-SCR initially installed on two turbines did not function properly. Subsequently, a modified hot-SCR system is being installed and tested.
>
> City of Redding Municipal Utilities, Redding, CA - 3 simple-cycle natural gas-fired GE Frame 5 turbines at 25 MW each. Water injection and hot-SCR installed on turbines does not function properly. The turbine exhaust is 900-950 °F. The facility lowers the NO_X emissions down to 40 ppmv with water injection followed by SCR to try to lower it further down to 9 ppmv - the permit limit. The facility is experiencing recurring plugging problems with the catalyst which is rapidly deteriorating under the severe thermal conditions and also blinding readily. The NO_X control efficiency has dropped significantly and the ammonia slip has risen above the typical 10 ppmv range. The catalyst vendor has been contacted to remedy the reduced performance. The facility is now contemplating conversion to combined-cycle operations.
>
> Puerto Rico Electric Power Authority - 3 ABB 80 MW each simple-cycle #2 oil-fired turbines. Hot-SCR not operating as promised by catalyst manufacturer with high soot buildup on catalyst. Additional ammonia injection has not helped lower NO_x emissions. Major effort underway by catalyst manufacturer to modify the system so that the required emission limits can be met.

The SCR process is also subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result either of prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalyst suppliers typically guarantee 3-year lifetimes for very low emission level, high performance catalyst systems.

SCR manufacturers typically estimate 10 ppm of unreacted ammonia emissions (ammonia slip) when making guarantees at very high efficiency levels. To achieve high NO_X reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which results in ammonia slip. Thus an emissions trade-off between NO_X and ammonia occurs in high NO_X reduction applications.

Finally, an add-on SCR control technology will add 2.5 to 4.5 inches WC backpressure on the turbine. Based on the Industrial Combustion Coordinated Rulemaking (ICCR) combustion work groups 1998 estimates, there is a 0.15% peak power generation capacity penalty per inch of pressure drop. This translates to significant loss of power generation capacity and loss of revenue for the GENCO Site.

The above discussion indicates that hot SCR technology has technical challenges. However, conventional SCR systems are considered as technically feasible control options and are further analyzed as BACT.

Selective Non-Catalytic Reduction (SNCR)

Operating temperature of SNCR must be between 1,300°F to 2,000°F. The combustion turbine exhaust maximum temperature is 915°F. At this or lower temperatures, the chemical reactions in the SNCR process will not occur. It is impractical to heat up the large volume of turbine exhaust gases to the desired SNCR temperature. No SNCR application in combustion turbine NO_X control is found in the EPA RBLC database. Therefore, the SNCR option is eliminated from further evaluation.

Non-Selective Catalytic Reduction (NSCR)

In the NSCR process, hydrocarbon and CO are adsorbed on the catalyst and become strong reducing agents. They can reduce NO_X to N_2. This reaction will take place only when there is no other compounds that are stronger oxidants than NO_X. In combustion turbine exhaust gases, the oxygen level is at about 11% to 15% by volume. With the presence of such a high level of oxygen in the gas stream, CO and hydrocarbon will react with oxygen, rather than NO_X, and NO_X reduction will not be achieved. Therefore, NSCR is not a technically feasible option.

Dry Low NO_X (DLN) Combustor

A DLN combustor is a technically feasible control option. This option has been used in the past and represents the leading edge technology that offers low NO_X emissions and additional operational flexibility at the present time. DLN combustors typically result in NO_X emission levels of 9 to 25 ppmv depending on turbine design (aero-derivative or frame) and size.

Water or Steam Injection

Wet controls such as water or steam injection systems are readily available with most turbine vendors. Performance of a wet control alternative is affected by combustor geometry, injection nozzle design, and fuel bound nitrogen content. In order to derive maximum control system performance, the injected water must be atomized and sprayed in a configuration that provides a homogeneous mixture of water droplets and fuel in the combustor. Water or steam injection for NO_X control is a feasible option. Water or steam injection typically results in NO_X emission levels of 25 to 42 ppmv. The GE LM6000 turbines can achieve NO_X emission levels of 25 ppmv.

Thus the only feasible control options for the proposed combustion turbines are $SCONO_x$™, SCR, DLN combustor, and water or steam injection. $SCONO_x$™ is the most effective of the four control options. SCR is the next most effective control option. DLN and water or steam injection have equivalent control efficiencies of 25 ppmv. These options are further analyzed in the order of their efficiencies to determine BACT. Since DLN and water or steam injection result in the same control, water or steam injection is only review based on the manufacturer recommending water or steam as the preferred method of control.

d) Environmental Impacts

This section discusses the environmental impacts of the technically feasible control options.

<u>$SCONO_x$™</u>

There are no significant environmental impacts from $SCONO_x$™ applications.

<u>Selective Catalytic Reduction</u>

Significant environmental impacts are associated with the use of an SCR system for NO_X control. These environmental impacts are summarized below:

SCR diminishes power output of the turbines due to pressure drop. Additional air pollutants will have to be emitted from some other power plant to make up for this wasted power;

Unreacted ammonia would be emitted to the atmosphere (ammonia slip); ammonia is a PM_{10} precursor;

Small amounts of ammonium salts would be emitted to the atmosphere as PM_{10};

There are serious (albeit manageable) safety issues associated with the transportation, handling, and storage of aqueous ammonia. The storage of aqueous ammonia (which is substantially lower risk than for anhydrous ammonia) is regulated under Occupational Safety and Health Act (OSHA) regulations and the Risk Management Planning (RMP) provisions of Clean Air Act Amendments Title III, Section 112(r); and

The use of SCR technology could result in ammonia emissions of as much as 20 ppm due to unreacted ammonia leaving the SCR unit. It is important to note that ammonia slip levels vary over the life of the catalyst. With a fresh catalyst, slip levels of only a few ppm may be sufficient to maintain the permitted NO_X emission rate. As catalyst ages, more ammonia (slip) is required, up to the point that the catalyst must be replaced.

In summary, the transport, handling, and storage of aqueous ammonia presents limited environmental risks due to potential spills and subsequent evaporation of ammonia gas to the atmosphere. However, potential environmental impacts from the storage and handling of aqueous ammonia are not considered unreasonable for the GENCO Site.

<u>Water or Steam Injection</u>

There are no significant environmental impacts from steam or water injection.

e) Economic Evaluation

This section evaluates the economic feasibility of each control option. Economic feasibility may be evaluated by estimating the cost effectiveness of each control option. Cost effectiveness is the ratio of the annualized cost of the control option and the tons of pollutant removed. The total annualized cost is based on capital cost and annual operation costs. The capital cost includes equipment costs, other direct and indirect installation and startup costs. Capital costs are based on budgetary quotations from equipment manufacturers. The direct and indirect installation costs are percentages of equipment costs. Annual operating costs include catalyst replacement, energy impacts, operating personnel, annual operation and maintenance costs, reagents and chemical costs, and heat rate penalty. The heat rate penalty cost item reflects the cost due to the control device backpressure losses. The additional backpressure will derate the combustion turbine resulting in lost electric sales revenue.

<u>$SCONO_X$™</u>

$SCONO_X$™ capital equipment includes the catalyst housing, auxiliary equipment, instrumentation, catalyst, and structural support. The total purchased equipment cost is based on a quote provided by Goal Line Technology (proposal dated June 15, 2000) and is $1,936,000. This includes the cost of temperature reduction system (heat exchangers) required for proper operation of the system. With other direct and indirect installation and start-up costs, the total capital cost for installing a $SCONO_X$™ system is estimated at $3,116,960.

The total annualized cost for operation of the $SCONO_X$™ system for each turbine is estimated at $863,249. The maximum amount of NO_X removed annually by the $SCONO_X$™ system would be 85 tons based on 4,000 hours of operation and an estimated removal efficiency of approximately 90 percent (reducing NO_X emissions from 30 ppm to 3.5 ppm). Therefore, the overall cost-effectiveness of the SCONOx™ system is calculated as approximately $10,180 per ton of NOx removed. Therefore, the SCONOx™ system is not a cost-effective technology for control of NOx from the proposed turbines at the GENCO Site.

Selective Catalytic Reduction

SCR capital equipment includes the catalyst housing, auxiliary equipment, instrumentation, ammonia storage and distribution, catalyst, and structural support. The total purchased equipment cost is estimated at $1,475,600 based on a quote from Engelhard. With other direct and indirect installation and start-up costs, the total capital cost for installing an SCR system is estimated at $1,783,800.

The total annualized cost for operation of SCR for each turbine is estimated at $633,400. The maximum amount of NOx removed annually by SCR would be 69 tons based on 4,000 hours of operation and an estimated removal efficiency of approximately 70 percent (reducing NOx emissions from 30 ppm to 9 ppmv). Therefore, SCR has an overall cost-effectiveness of approximately $9,200 per ton of NOx removed. Therefore, SCR is not a cost-effective technology for control of NOx from the proposed turbines at the GENCO Site.

Water or Steam Injection

Water or steam injection is considered economically feasible and, therefore, is not reviewed here.

f) Proposed BACT for NO_X

The GE LM6000 turbines when equipped with water or steam injection results in NOx emissions of 25 ppmv. Based on the economic infeasibility of SCONOx™ and SCR for the proposed peaking application, water or steam injection with NOx emissions of 25 ppmv is proposed as BACT for this project.

g) Proposed BACT Review

Based on the costs associated with SCONOx™ and SCR, $10,180 and $9,200 per ton of NOx removed respectively, these controls are not economically effective.

Additionally, the proposed BACT was reviewed against BACT determinations in the RACT/BACT/LAER Clearinghouse (RBLC). The RBLC is a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), and lists technologies that have been approved in PSD permits as BACT for numerous process equipment. The purpose of the RBLC database search is to identify the emission control technologies and levels of NOx emissions that were determined by permitting authorities as BACT for combustion turbines of similar size. The search result does not include turbines 70 MW or larger since these are not aeroderivative models. The results of this search are listed below.

PERMIT ID	PERMIT ISSUED	PERMITTED ITEM	SIZE**	EMISSION LIMIT	CONTROL EQUIPMENT
FL-0109	9/28/95	Turbine relocation	23 MW	75 ppmv	Water injection
AL-0096	3/12/97	Combined cycle	25 MW	25 ppmv	DLN
CO-0037	1/4/99	Combined cycle	33 MW	15 ppmv	Pollution prevention
NM-0024	5/29/95	Turbine	33 MW	9 ppmv	DLN
WY-0039	2/27/98	Turbine	33 MW	25 ppmv	DLN
CO-0018	7/20/94	Turbine	35 MW	25 ppmv	DLN
MO-0013	7/27/95	Twin-pac turbine	35 MW	42 ppmv***	Water injection
LA-0093	3/7/97	Combined cycle	38 MW	9 ppmv	DLN
LA-0113	12/30/97	Turbine	38 MW	8 ppmv	Steam injection and SCR
CO-0019	12/30/97	Combined cycle	39 MW	42 ppmv	Water injection
CO-0017	7/26/96	Turbine*	40 MW	25 ppmv	Steam injection
WY-???	3/1/00	Turbine*	40 MW	25 ppmv	DLN
NM-0039	8/7/98	Combined cycle*	44 MW	15 ppm	Water injection and SCR
AR-???	2/28/00	Combined cycle*	46 MW	25 ppmv****	Steam injection
ME-0015	3/31/98	Combined cycle	49 MW	6 ppmv	DLN and SCR

* turbines are aeroderivative GE LM6000 models
** all sizes are simple cycle
*** 1-hour average
**** 22 ppmv, 12-month rolling average

As shown, the BACT determinations varied from 8 ppm to 75 ppm. The more recent determinations indicate a move to 25 ppm or less and only one recent determination has been made that requires additional controls (NM-0039). This source is a combined cycle system which results in the SCR controlling higher levels of NO_X providing a more cost effective SCR system.

Based on technically feasible controls, the historical BACT review, and the cost effectiveness of additional controls, BACT is accepted as water or steam injection with NO_X emissions of 25 ppmv corrected to 15% O_2.

SECTION IX. AIR QUALITY IMPACTS AND MONITORING (From Permit No. 2000-273-C (PSD))

The air quality impact analyses were conducted to determine if ambient impacts would result in a radius of impact being defined for the facility. If a radius of impact occurs for a pollutant then a full impact analysis is required for that pollutant. If the air quality analysis does not indicate a radius of impact, no further air quality analysis is required.

Description of Air Quality Dispersion Model

The air quality modeling analyses employed USEPA's Industrial Source Complex Short Term Version 3 (ISC3) model. The ISC3 model is recommended as a guideline model for assessing the impact of aerodynamic downwash (40 CFR 40465-40474).

The ISC3 model (Version 99155) consists of two programs: a short-term model (ISCST3) and a long-term model (ISCLT3). The difference in these programs is that the ISCST3 program utilizes an hourly meteorological data base, while ISCLT3 is a sector-averaged program using a frequency of occurrence based on categories of wind speed, wind direction, and atmospheric stability. The ISCST3 model was used. The regulatory default option, which includes stack heights adjusted for stack-tip downwash, buoyancy-induced dispersion, and final plume rise. Ground-level concentrations occurring during "calm" wind conditions are calculated by the model using the calm processing feature. Regulatory default values for wind profile exponents and vertical potential temperature gradients are used since no representative on-site meteorological data are available. As per U.S. EPA requirements, direction-specific building dimensions are used for both the Schulman-Scire and the Huber-Snyder downwash algorithms.

Additionally, the rural settings were used based on the area being made up of primarily cropland and pasture. Stack base elevation for the proposed units is 360 meters. All receptors that are below this elevation are raised to 360 meters to be conservative. All receptors that fall outside the 12 nearest quadrangles are set to stack base elevation.

GEP Stack Height and Plume Downwash

The emissions units at the GENCO site have been evaluated in terms of their proximity to nearby structures. The purpose of this evaluation is to determine if stack discharges might become caught in the turbulent wakes of these structures. Wind blowing around a building creates zones of turbulence that are greater than if the building were absent. The current version of the ISCST3 dispersion model provides for a revised treatment of building wake effects which, for certain emissions units, uses wind direction-specific building dimensions following the algorithms developed by Schulman and Hanna. The minimum stack height not subject to the effects of downwash is defined by the formula:

$$G = H + 1.5L$$

Where: G = Minimum Good Engineering Practice (GEP) stack height
H = Height of the structure
L = Lesser dimension (height or projected width of structure)

This equation is limited to stacks located within 5L of the structure. Stacks located at distances greater than 5L are not subject to the wake effects of the structure. If there is more than one stack at a given facility, the above equation must be successively applied to each stack. If more than one structure is involved, the equations must also be successively applied to each structure.

Direction-specific building dimensions and the dominant downwash structure parameters used as input to the dispersion models were determined using the *BREEZE-WAKE/BPIP* software, developed by Trinity Consultants. This software incorporates the algorithms of the U.S. EPA sanctioned Building Profile Input Program (BPIP), version 95086. BPIP is designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, the Building Downwash Guidance document, and other related documents.

The output from the BPIP downwash analyses lists the names and dimensions of the structures, and the emissions unit locations and heights. In addition, the output contains a summary of the dominant structure for each emissions unit (considering all wind directions) and the actual building height and projected widths for all wind directions. This information is then incorporated into the data files for the ISCST3 model.

Meteorological Data

The ISCST3 air dispersion modeling is performed using 1986 through 1988 preprocessed meteorological data based on surface observations taken from Oklahoma City, Oklahoma (National Weather Service Station [NWS] station number 13967) with upper air measurements from Oklahoma City, Oklahoma. 1990 and 1991 preprocessed meteorological data based on surface observations taken from Oklahoma City, Oklahoma is also used with upper air measurements from Norman, Oklahoma (NWS station number 3948). 1989 meteorological data was not used because the upper air data station was moved from Oklahoma City to Norman midway through the year. Due to the fact that a PSD analysis is being conducted, the five most recent years of meteorological data are used. The formaldehyde analysis uses the most recent year of meteorological data (1991).

The anemometer height at the Oklahoma City, Oklahoma NWS station during the period of interest was 6.1 meters.

Receptor Grid

In the air dispersion modeling analysis, ground-level concentrations are calculated within four Cartesian receptor grids. These four grids cover a region extending 50 km from all edges of the proposed facility fenceline. Initially, a "coarse grid" that contains 1-km spaced receptors extending 50 km from the property fenceline is employed to isolate a localized area of maximum concentrations. Since the maximum concentrations are found to be on or very near the facility fenceline, the remaining grids are defined as follows:

1) a "fenceline" grid consisting of evenly-spaced receptors 100 meters apart placed along the proposed facility fenceline

2) a "fine" grid containing 100-meter spaced receptors extending approximately 1.0 km from the fenceline exclusive of the receptors within the proposed facility fenceline

3) a "medium grid" containing 500-meter spaced receptors extending 5 km from the fenceline exclusive of receptors in the fine grid.

4) a "coarse grid" containing 1,000-meter spaced receptors extending 50 km from the fenceline exclusive of receptors in the fine and medium grid.

Due to maximum NO_2 concentrations on the medium grid, a fine grid was centered around the maximum concentration. A "medium-fine" grid was created to capture the maximum NO_2 concentration.

Modeled Emission Rates and Stack Parameters

All proposed emissions units at the GENCO site are considered in the modeling analysis except the black start generator since under normal operations these will not function during turbine operation. The largest pollutant emission rate that meets the requirements of the best available control technology (BACT) analysis are used for each pollutant. Pollutants that are evaluated include NO_X (as nitrogen dioxide [NO_2]) and formaldehyde. In addition, all contemporaneous emissions increases from the Anadarko WFEC site are included in the modeling analysis. 1999 calender year actual emissions are modeled as the actual emissions increases for the contemporaneous emissions increase units. These emission rates are used since it is representative of normal operations. This increase was the result of adding two boilers. As a conservative estimate, no contemporaneous emissions decreases are modeled in this analysis.

The stack emission rates and parameters needed for the proposed addition included each exhaust stack for the two CTs and each of the exhaust stacks for the two existing boilers.

The proposed CTs can operate at various loads. For modeled emissions of NO_X from the CTs, the maximum annual emission rate at 100% load for each turbine based on the 25 ppm BACT at the annual average temperature of 60 °F and 4,000 hours/year is 79.64 TPY. The short term NO_X emission rate modeled for each turbine is the maximum expected rate, 41 lb/hr, at the 25 ppm BACT requirement. In order to identify a worst case dispersion scenario for the CTs, the minimum exhaust temperature and minimum exit velocity at 100% load were modeled for each of the CT exhaust stacks. Boiler stack parameters are based on average annual conditions.

EU	Stack Height (m)	Velocity (m/sec)	Temperature (°K)	Diameter (m)	Emission Rate (g/sec)
CT #1	13.72	42.97	694.26	2.74	5.17
CT #2	13.72	42.97	694.26	2.74	5.17
Boiler #1	30.78	0.63	435.93	1.83	0.0457
Boiler #2	30.78	0.63	435.93	1.83	0.0287

Modeling Results

The modeling results are shown below. The modeling indicates emissions from the modification will result in ambient concentrations below the significance levels in which an area of impact is defined. Therefore, no additional modeling for PSD increment or NAAQS compliance is required.

Significance Level Comparisons

Pollutant	Averaging Period	Receptor Grid	Maximum Concentration ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
NO_X	Annual	Fenceline	0.394	1.0
		Fine	0.452	1.0
		Medium	0.578	1.0
		Coarse	0.469	1.0
		Medium-Fine	0.679	1.0

Ambient Monitoring

The U.S. EPA's monitoring *de minimis* concentrations establish the levels at which a facility would need to conduct pre-construction ambient air quality monitoring to demonstrate compliance with the NAAQS and PSD increments for criteria pollutants. If modeling analyses show that maximum concentrations from a proposed facility do not exceed the monitoring *de minimis* concentrations, pre-construction monitoring can be avoided. As demonstrated below emissions of NO_2 from the proposed units will not result in ambient concentrations in excess of the monitoring *de minimis* level.

Comparison of Modeled Impacts to Monitoring Exemption Levels

Pollutant	Monitoring Exemption Levels		Ambient Impacts
	Averaging Time	$\mu g/m^3$	$\mu g/m^3$
NO_X	annual	14	0.679

SECTION X. ADDITIONAL IMPACTS ANALYSIS (From Permit No. 2000-273-C (PSD))

Mobile Sources

Current EPA policy is to require an emissions analysis to include mobile sources. In this case, mobile source emissions are expected to be negligible. Few additional employees will be needed for the proposed peaking plant. The fuel for the plant will arrive by pipeline rather than by vehicle.

Growth Impacts

Since a minimal small permanent staff will be required by the plant, no significant air quality impact from growth is expected. Construction of the plant should not result in an increase in the number of permanent residents. No significant industrial or commercial secondary growth will occur as a result of the project since the number of permanent employees needed is small. Most labor, material, and service requirements are already in place.

Soils and Vegetation

The following discussion will review the projects potential to impact its agricultural surroundings based on the facilities allowable emission rates and resulting ground level concentrations of SO_2 and NO_X. SO_2 and NO_X were selected for review since they have been shown to be capable of causing damage to vegetation at elevated ambient concentrations.

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

SO_2 enters the plant primarily through the leaf stomata and passes into the intercellular spaces of the mesophyll, where it is absorbed on the moist cell walls and combined with water to form sulfurous acid and sulfite salts. Plant species show a considerable range of sensitivity to SO_2. This range is the result of complex interactions among microclimatic (temperature, humidity, light, etc.), edaphic, phenological, morphological, and genetic factors that influence plant response (USEPA, 1973).

NO_2 may affect vegetation either by direct contact of NO_2 with the leaf surface or by solution in water drops, becoming nitric acid. Acute and chronic threshold injury levels for NO_2 are much higher than those for SO_2 (USEPA, 1971).

The secondary NAAQS are intended to protect the public welfare from adverse effects of airborne effluents. This protection extends to agricultural soil. As evaluated in the dispersion modeling report, the maximum predicted NO_2 pollutant concentration from the proposed power plant will be well below the secondary NAAQS. Further, expected emissions of SO_2 will be below the PSD applicability threshold and the level at which a significant impact review is required, therefore, no significant impact is expected. Since the secondary NAAQS protect impact on human welfare, no significant adverse impact on soil and vegetation is anticipated due to the proposed modification.

Visibility Impairment

The project is not expected to produce any perceptible visibility impacts in the vicinity of the plant. EPA computer software for visibility impacts analyses, intended to predict distant impacts, terminates prematurely when attempts are made to determine close-in impacts. It is concluded that there will be minimal impairment of visibility resulting from the facility's emissions. Given the limitation of 20% opacity of emissions, and a reasonable expectation that normal operation of the natural gas fired combustion turbines will result in 0% opacity, no local visibility impairment is anticipated. The visual impact of a plume from the project on the Class I area is examined using the Plume Visual Impact Screening Model (VISCREEN). The VISCREEN model is run in the Screening Level 1 mode following the guidance in EPA's Workbook for Plume Visual Impact Screening and Analysis (EPA-450/4-88-015). The PM and NO_X emissions modeled in the visibility analysis are based on the maximum proposed emissions from the GENCO Site. Regional background visual ranges are input to the model following guidance from the workbook referenced above. The model is run with default values for the remainder of the input parameters. The VISCREEN analysis showed that impacts do not exceed screening criterion.

Class I Area Impact Analysis

The objective of this regional haze analysis is to demonstrate that emissions from the proposed project will not cause a noticeable extinction change (<5%) in the nearby Class I areas, i.e., Wichita Mountains, which is approximately 35 km from the GENCO Site.

Results of the modeling analysis demonstrate that the proposed project will not adversely affect visibility at the Wichita Mountains. The remainder of this section discusses the methods used in the analysis and the results of the analysis.

Regional Haze Analyses

Federal Class I areas are places of special national or regional value from a natural, scenic, recreational, or historic perspective. These areas were established as part of the PSD regulations included in the 1977 Clean Air Act Amendments. Federal Class I areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations.

Regional haze occurs at distances where the plume has become evenly dispersed into the atmosphere, such that there is no definable plume. The primary causes of regional haze are sulfates (SO_4) and nitrates (NO_3) (primarily as ammonium salts), which are formed from sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) through chemical reactions in the atmosphere. These reactions take time, such that near a source little NO_X or SO_2 will have formed nitrate or sulfate, whereas far from a source nearly all SO_2 will have formed sulfate and most NO_X will have formed nitrate. Regional haze analyses are generally considered when the distance between a facility and a Class I area is 50 km or greater.

Regional haze is measured using the light extinction coefficient (b_{ext}). To determine a change in regional haze, the percentage change of the light extinction coefficient is evaluated (Δb_{ext}), calculated as shown in the following equation.

$$\Delta b_{ext} = \frac{b_{ext,project}}{b_{ext,background}}$$

The background extinction coefficient is affected by various chemical species and the Rayleigh scattering phenomenon and can be calculated as follows:

$$b_{ext,background}(Mm^{-1}) = b_{SO_4} + b_{NO_3} + b_{OC} + b_{soil} + b_{coarse} + b_{ap} + b_{ray}$$

where,

$$b_{SO_4} = 3[(NH4)2SO4]f(RH)$$
$$b_{NO_3} = 3[NH_4NO_3]f(RH)$$
$$b_{OC} = 4[OC]$$
$$b_{Soil} = [Soil]$$
$$b_{Coarse} = 0.6[Coarse\ Mass]$$
$$b_{ap} = 10[Elemental\ Carbon]$$
$$b_{Ray} = Rayleigh\ Scattering$$
$$f(RH) = relative\ humidity\ adjustment\ factor$$
$$[\quad] = Concentration\ in\ \mu g/m^3$$

Per Federal Land Managers Air Quality Related Values Workgroup (FLAG) recommendations, Rayleigh scattering was assumed to be 10 Mm^{-1}. The extinction coefficient due to emissions increases from the proposed project was also calculated. Three visibility-related pollutants (SO_2, NO_X, and PM_{10}) will be emitted from the proposed project. As discussed earlier, part of the SO_2 and NO_X are transformed to $(NH_4)_2SO_4$ and NH_4NO_3, which unlike their precursors, have the potential to cause haze impacts. The extinction due to the project ($b_{ext,project}$) can be calculated as follows:

$$b_{ext,project}(Mm^{-1}) = b_{SO_4} + b_{NO_3} + b_{PM}$$

where,

$$b_{SO_4} = 3[(NH_4)_2SO_4]f(RH)$$
$$b_{NO_3} = 3[NH_4NO_3]f(RH)$$
$$b_{PM} = [PM_{10}]$$
$$f(RH) = \text{relative humidity adjustment factor}$$
$$[\quad] = \text{Concentration in } \mu g/m^3$$

Per FLAG recommendations, if the hourly relative humidity exceeds 95% it was rolled back to 95%, so that there were no *f*(RH) factors applied greater than *f*(95%).

The Δb_{ext} value attributable to a single facility that is acceptable to the Federal Land Managers (FLM) for a single facility is 5% on a 24-hour average basis. If impacts from a single facility exceed 5%, the applicant may model a full inventory of facilities and compare against a Δb_{ext} value of 10%. Unlike the U.S. EPA standards, there is no prescribed number of allowed exceedances. Depending on the details of each case, the FLM may approve an analysis that shows some exceedances of the 5% or 10% threshold.

Dispersion Modeling Methodology

Version 5.4 (Level 0006021) of the CALPUFF model was used to determine the possible impacts of the proposed project on visibility.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model, which can simulate the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal. In this CALPUFF screen analysis, the single meteorological station method was used.

A series of input files were used by the CALPUFF model to enter the necessary source, receptor, meteorological information, and control parameters. The selection and control of CALPUFF options are determined by user-specific inputs contained in the control file. This file contains all the information necessary to define a model run (e.g., starting date, run length, grid specifications, technical options, output options).

The dispersion modeling was performed using CALPUFF default options, except as specifically noted in this section.

CALPUFF Modeling Grids

The CALPUFF modeling system utilizes three modeling grids (i.e., meteorological grid, computational grid, and sampling grid). The meteorological grid is the system of grid points at which meteorological parameters (wind components, mixing heights, etc.) are defined. The computational grid determines the computational area for a CALPUFF run. Puffs are advected and tracked only while within the computational grid. It should be noted that the location of non-gridded (discrete) receptors are not limited to within the sampling grid. The sampling grid may be eliminated entirely if sufficient coverage can be obtained with non-gridded receptors. In this analysis, a sampling grid will not be defined since only discrete receptors are being considered.

Grid settings are as follows: NX = 2; NY = 2; NZ = 1; Cell Face Heights = 0, 5000m; Grid Spacing = 200 km. The CALPUFF computational grid is at least 50 km beyond the farthest boundary of the Class I area.

Meteorological Data

The FLAG report recommends a two-phase process for determining whether a source adversely impacts the AQRV in a Class I area. Tier 1 uses the "CALPUFF Screen" methodology contained in the IWAQM Phase II report, Section 4.8. This approach couples the CALPUFF model with ISC-formatted meteorological data. Tier 1 takes advantage of the time-varying calculations for atmospheric chemistry while maintaining the simplicity of a spatially constant meteorological set.

If the Tier 1 analysis had shown unfavorable results for visibility, a full CALPUFF modeling effort could have been undertaken. However, given the minimal impact shown by the Tier 1 analysis, the effort required for a full CALPUFF analysis is not warranted.

For this analysis, Trinity used preprocessed meteorological data based on surface measurements and upper air measurements taken in Oklahoma City, Oklahoma (station number 13967) for 1986, 1987, 1988, 1990, and 1991. Note that 1989 was not used because the meteorological data taken at the station is incomplete. The anemometer height used in this analysis was 6.1 meters. Trinity used Oklahoma City humidity, precipitation, and radiation data from the Solar and Meteorological Surface Observational Network (SAMSON) for the same time period.

The CALPUFF model was run continuously for years 1986-1988 and 1990. The model was not run for the 1991 data because the solar radiation information was not available. As a result, the CALPUFF model was run for four years, which should provide a sufficient basis for evaluating the potential impacts from this project.

Site-specific information used in the meteorological data processing are shown below.

Site-Specific Parameter Values

Parameter	Value
Site Latitude	35.39 ° N
Site Longitude	97.60 ° W
Zone	6
Surface Roughness (m)	0.4035
Albedo	0.254
Bowen Ratio	0.80
Minimum Monin-Obukhov Length (m)	2
Fraction of Net Radiation Absorbed at the Ground (Rural)	0.15
Anthropogenic Heat Flux (W/m^2)	0

Met/Land-Use Analysis

The Met/Land-Use variables (land use, leaf area index, and roughness length) are set as "domain average" values. More specifically, a weighted average for each variable has been calculated based on the "sector of interest" (i.e. geographic area between the source and Class I area where the plume is most likely to travel). If the spatial variability is significant and important, it might be necessary to generate a full run where a GEO.DAT file can be used to properly handle spatial variability. In this project, the land use type is 60% cultivated land and 40% forest. The surface roughness and leaf area index has been determined based on the land use type.

The elevation in the "Met/Land-Use" section contains the ELEVIN variable. Since there is no GEO.DAT file in a CALPUFF Screen (ISC-mode) run, the single elevation value specified in ELEVIN is used to specify the elevation for all gridded receptors. Since only discrete receptors are used in a CALPUFF Screen run, this variable is not critical. It has been set to the meteorological station elevation. The latitude and longitude values in the "Met/Land-Use" section have been set to those of the meteorological station.

Based on the USGS maps of the area surrounding the proposed facility, the area surrounding the proposed facility site is rural. Therefore, rural dispersion coefficients have been utilized in the air dispersion modeling analysis.

Receptor Selection

The CALPUFF modeling receptors were arranged in two rings of 360 receptors centered on the emission sources. The radius of the innermost ring is 35 km, the shortest distance between the source and Wichita Mountains. An elevation of 468 meters (average elevation for receptors inside the Class I area) has been assigned to all 360 receptors in this ring. The outermost ring is at a radius of 74 km, the farthest distance between the source and Wichita Mountains. The elevation of this point, 415 meters, has been assigned to all receptors in this ring.

Point Source Stack Parameters

The CALPUFF dispersion model allows for emission units to be represented as point, area, or volume sources. The two combustion turbine (CT) stacks and the two electric power generation units (EPGU) have been included as point sources in this analysis.

Building Downwash Analysis

The modeled emission sources in the proposed project were evaluated in terms of their proximity to nearby structures. The purpose of this evaluation is to determine the possibility of the discharges being entrained in the turbulent wakes of any structures. The latest version (95086) of the U.S. EPA Building Point Input Program (BPIP) was used to determine the direction-specific downwash dimensions and the dominant downwash structures used in this analysis. The BPIP output file was incorporated into the CALPUFF input file.

Chemical Transformation

The CALPUFF model is capable of modeling linear chemical transformation effects by using pseudo-first-order chemical reaction mechanisms for the conversion of sulfur dioxide (SO_2) to sulfate (SO_4), and nitrogen oxides (NO_X), which consist of nitric oxide (NO) and nitrogen dioxide (NO_2), to nitrate (NO_3) and nitric acid (HNO_3). In this study, six species (SO_2, SO_4, NO_X, HNO_3, NO_3, and PM_{10}) were modeled. The MESOPUFF II chemical transformation scheme was used.

The model required background concentrations for ozone (O_3) and ammonia (NH_3), and nighttime conversion rates for SO_2, NO_X, and HNO_3. A conservative estimate was used to base the background O_3 and NH_3 concentrations. CALPUFF default values were used for the nighttime conversion rates for SO_2, NO_X, and HNO_3. The chemical parameters are shown below.

CALPUFF Chemical Parameter Values

Species	Value
O_3	60 ppb
NH_3	10 ppb
SO_2	0.2 percent per hour
NO_X	2.0 percent per hour
HNO_3	2.0 percent per hour

Modeling Results

Model results were post processed with the CALPOST program. The following table lists the 25 maximum predicted visibility impacts for the four-year period. The threshold guideline of 5% was not exceeded on any day during the five years at any of the 720 receptors. The maximum predicted impact was 3.94%.

Maximum Predicted Visibility Impacts

Rank	Year	Day	UTM East (km)	UTM West (km)	Extinction Change (%)
1	1988	338	571.097	3917.413	3.94
2	1986	308	572.928	3847.503	3.47
3	1988	9	590.058	3853.402	3.13
4	1986	301	576.564	3916.886	3.10
5	1986	311	559.670	3915.705	3.07
6	1986	332	575.961	3847.849	3.07
7	1986	10	585.278	3914.139	2.87
8	1991	1	554.596	3913.604	2.82
9	1986	281	568.045	3917.333	2.70
10	1988	327	581.302	3849.131	2.67
11	1986	322	559.091	3849.325	2.59
12	1986	359	580.133	3848.774	2.57
13	1986	133	554.596	3913.604	2.51
14	1987	53	587.454	3851.807	2.48
15	1988	192	561.427	3916.226	2.40
16	1986	21	566.828	3917.227	2.37
17	1987	27	563.209	3848.183	2.37
18	1987	20	589.033	3852.737	2.36
19	1990	7	583.029	3849.743	2.36
20	1987	344	598.438	3903.482	2.32
21	1986	346	598.802	3902.991	2.31
22	1987	46	560.253	3915.889	2.29
23	1986	290	592.034	3909.999	2.28
24	1990	8	569.875	3917.413	2.28
25	1990	62	581.302	3849.131	2.28

The lack of exceedances of the recommended visibility thresholds indicate that the proposed project will not contribute to increased visibility impairment at the Wichita Mountains Wildlife Refuge.

SECTION XI. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-4 (New Source Performance Standards) [Applicable]
Federal regulations in 40 CFR Part 60 are incorporated by reference as they exist on July 1, 2002, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Ca, Subpart Cb, Subpart Cc, Subpart Cd, Subpart Ce, Subpart AAA, and Appendix G. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-5 (Registration, Emission Inventory, and Annual Operating Fees) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories have been submitted and fees paid for the past years.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAP or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emission limits for the facility are based on Permit No. 2000-273-C (PSD) and information in the application.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report

for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for mitigation, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter) [Applicable]
This subchapter specifies a particulate matter (PM) emission limitation of 0.6 lb/MMBTU from existing fuel-burning equipment with a rated heat input of 10 MMBTUH or less. For fuel-burning equipment greater than 10 MMBTUH but less than 1,000 MMBTUH, this subchapter specifies a PM emission limitation (E) based on the heat input of the equipment (X) and calculated using the equation from Appendix C ($E = 1.042808X^{-0.238561}$). The heat input, calculated PM emission limitation, and expected emissions from all of the fuel-burning equipment are shown in the table below.

EU	Max. Heat Input (MMBTUH) (HHV)	Allowable PM Emission Rate (lb/MMBTU) (HHV)	Potential PM Emissions (lb/MMBTU) (HHV)
AN-UNIT7	452	0.24	0.01
AN-UNIT8	452	0.24	0.01
AN-Emerg. Gen	5.17	0.6	0.08

The permit will require the use of natural gas or distillate fuel (fuel oil No. 2) for all fuel-burning equipment to ensure compliance with Subchapter 19.

OAC 252:100-25 (Visible Emissions and Particulate Matter) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. When burning natural gas there is little possibility of exceeding the opacity standards.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility will not cause a problem in this area, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 affects new fuel-burning equipment that was constructed after July 1, 1972. The two simple cycle gas turbines (AN-UNIT7 and AN-UNIT8) are subject to the new equipment standard which limits SO_2 emissions from gaseous fuels to 0.2 lb/MMBTU heat input, based on a three-hour average. For fuel gas having a gross calorific value of 1,000 BTU/SCF, this limit corresponds to fuel sulfur content of 1,203-ppmv. AP-42 (7/98), Table 1.4-2, lists the total SO_2 emissions for natural gas to be 0.6 lb/MMft^3 or about 0.0006 lb/MMBTU which is in compliance with Subchapter 31. When burning natural gas, the permit requires the use of gaseous fuel with a sulfur content of less than 343-ppmv to ensure compliance with Subchapter 31.

The diesel-fired emergency engine (Emerg. Gen.) is subject to the SO_2 emission limitation of 0.8 lb/MMBTU heat input, maximum three-hour average for liquid-fired fuel-burning equipment. NESHAP, Subpart ZZZZ limits this engine to low sulfur diesel with a maximum fuel sulfur content of 15 ppmw which based on AP-42 (10/96), Section 3.4 is approximately 0.0015 lb SO_2/MMBTU, which is in compliance with this limit.

Part 5 requires an opacity monitor and SO_2 monitor for equipment rated above 250 MMBTUH. Since the simple cycle turbines are limited to natural gas only, they are exempt from the opacity monitor requirement. Equipment burning gaseous fuel containing less than 0.1 percent sulfur is exempt from the SO_2 monitor requirement. Based on the pipeline-quality natural gas requirement, the simple cycle turbines will be exempt from the SO_2 monitoring requirement.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
NO_X emissions are limited to 0.20 lb/MMBTU, three-hour average, from all new gas-fired fuel-burning equipment with a rated heat input of 50 MMBTUH or greater. The two simple cycle gas turbines (AN-UNIT7 and AN-UNIT8) are subject to this requirement. AN-UNIT7 and AN-UNIT8 are controlled with water injection, which limits maximum hourly emissions to 41.0 lb/hr, which is equivalent to approximately 0.09 lb/MMBTU which is in compliance with this subchapter. The permit will incorporate the applicable emissions limit of 0.2 lb/MMBTU.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 7 requires fuel-burning and refuse-burning equipment to be operated and maintained so as to minimize VOC emissions. Temperature and available air must be sufficient to provide essentially complete combustion.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director. Since no AOC has been designated there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

Each emissions unit was evaluated for periodic testing in accordance with the Periodic Testing Standardization guidance issued December 1, 2011, on a pollutant by pollutant basis. The frequency of the periodic testing requirement is based on the quantity of the pollutant emitted. Periodic testing requirements are not required for an emission unit that is subject to an applicable requirement that already requires periodic testing, continuous emission monitoring (CEM), or predictive emission monitoring (PEMS). For this facility, NO_X and CO are the only pollutants which are potentially subject to the periodic testing requirements. All other pollutants emitted from this facility are less than 40 TPY per unit.

Periodic Testing Review

EU	Pollutant	TPY	Current Monitoring	Periodic Testing
AN-UNIT7[1]	NO_X	159.2	Part 60/75 PEMS	NO
	CO	91.0	None	NO[2]
AN-UNIT8[1]	NO_X	159.2	Part 60/75 PEMS	NO
	CO	91.0	None	NO[2]

[1] - These units are limited to a combined uncontrolled emission limits of 159.2 TPY of NO_X and 91.0 TPY of CO. However, a single unit could emit the entire amount.

[2] - Based on historical operation, these units were operated equally and the PTE of both units would be < 50 TPY. Therefore, periodic testing is not warranted.

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-7	Permits for Minor Sources	not in source category
OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain Elevators	not in source category

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-35	Carbon Monoxide	not type of emission unit
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Municipal Solid Waste Landfills	not in area category

SECTION XII. FEDERAL REGULATIONS

Protection of Visibility, 40 CFR 51 Subpart P [Applicable]
The primary purposes of this subpart are to require States to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution; and to establish necessary additional procedures for new source permit applicants, States and Federal Land Managers to use in conducting the visibility impact analysis required for new sources under §51.166. This subpart sets forth requirements addressing visibility impairment in its two principal forms: "reasonably attributable" impairment (i.e., impairment attributable to a single source/small group of sources) and regional haze (i.e., widespread haze from a multitude of sources which impairs visibility in every direction over a large area). Regional haze visibility impairment is partially addressed through the Best Available Retrofit Technology (BART) process. The facility has been determined to be subject to a BART review.

BART Requirements for Regional Haze Visibility Impairment
As indicated in Permit No. 2005-037-TVR (M-2), WFEC proposed to modify the affected units and established enforceable emissions limits such that the affected units would not cause or contribute to any impairment of visibility in any mandatory Class I Federal area. The BART exemption emission limits which were effective January 27, 2017 (5 years after SIP approval) were incorporated into the specific conditions of the permit.

PSD, 40 CFR Part 52 [Applicable]
Emissions of several regulated pollutants exceed 100 TPY, the level at which PSD defines the facility to be a major source. The modification authorizing the construction of the emission units affected by this permit went through PSD review. The original PSD evaluation is contained in Section VII through Section X. Removal of the 0.09 lb NO_X/MMBTU emission limit is not considered a modification and the original PSD evaluation and determinations were not altered. Any future expansion must be evaluated in the context of PSD significance levels (100 TPY CO, 40 TPY NO_X, 40 TPY SO_2, 40 TPY VOC, 25 TPY PM, 15 TPY PM_{10}, or 0.6 TPY lead).

NSPS, 40 CFR Part 60 [Subparts A, Db, GG, and KKKK are Applicable]
Subpart A, General Provisions. This subpart requires the submittal of several notifications for NSPS-affected facilities. Within 30 days after starting construction or modification of any affected facility, the affected facility must notify DEQ that construction has commenced. A notification of the actual date of initial start-up of any affected facility shall be submitted within 15 days after such date. Initial performance tests are to be conducted within 60 days of achieving the maximum production rate, but not later than 180 days after initial start-up of the

facility. The facility must notify DEQ at least 30 days prior to any initial performance test and must submit the results of the initial performance tests to DEQ.

Subpart GG, Stationary Gas Turbines. This subpart affects stationary gas turbines with a heat input at peak load of greater than or equal to 10.7 gigajoules per hour (10 MMBTUH) based on the lower heating value (LHV) of the fuel and that commenced construction, reconstruction, or modification after October 3, 1977. EU AN-UNIT7 and AN-UNIT8 have a heat input greater than 10 MMBTUH and are subject to this subpart. Subpart GG limits NO_X emissions to a minimum of 75 ppmvd (potentially higher based on heat rate and fuel nitrogen content) for the combustion turbines. Monitoring fuel for nitrogen content is not required if the owner or operator does not claim an allowance for fuel bound nitrogen per § 60.334(h)(2). The NO_X BACT requirement of 25 ppmdv for EU AN-UNIT7 and AN-UNIT8 is more stringent than the Subpart GG requirements. The facility will demonstrate continued compliance with the BACT limit using a predictive emission monitoring system (PEMS) or CEM. Subpart GG limits SO_2 emissions to 150 ppmdv or by limiting the fuel to less than or equal to 0.8% by weight sulfur. For fuel supplies without intermediate bulk storage, the owner or operator shall either monitor the fuel nitrogen and sulfur content daily or develop custom schedules of fuel analysis based on the characteristics of the fuel supply. The owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted if the gaseous fuel is demonstrated to meet the definition of "natural gas" using either the gas quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract, or using representative fuel sampling data. The maximum total sulfur content of "natural gas" is 20 grains/100 SCF (680 ppmw or 338 ppmv) or less. All applicable requirements are incorporated into the specific conditions.

Subpart IIII, Stationary Compression Ignition (CI) Internal Combustion Engines (ICE). This subpart affects CI ICE manufactured after 2007. There are no CI ICE manufactured after 2007 at this facility.

Subpart KKKK, Stationary Combustion Turbines. This subpart affects stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBTU) per hour, based on the higher heating value of the fuel that commenced construction, modification, or reconstruction after February 18, 2005. EU AN-UNIT7 and AN-UNIT8 were constructed prior to February 18, 2005, and have not been modified or reconstructed.

NESHAP, 40 CFR Part 61 [Not Applicable]

There are no emissions other than trace amounts of any of the regulated pollutants: arsenic, asbestos, beryllium, benzene, coke oven emissions, mercury, radionuclides or vinyl chloride.

NESHAP, 40 CFR Part 63 [Subparts ZZZZ and CCCCCC are Applicable]

Subpart YYYY, Combustion Turbines. This subpart was promulgated on March 5, 2004, and affects combustion gas turbines that are located at major sources. Emission calculations have shown this facility to be a minor source of HAP.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects RICE with a site-rating greater than 500 brake horsepower that are located at a major source and new and reconstructed engines (after June 12, 2006) with a site rating less than or equal to 500 HP located at major sources, and located at area sources. Owners and operators of new or reconstructed engines at area sources and of new or reconstructed engines with a site rating equal to or less than 500 HP located at a major source (except new or reconstructed 4-stroke lean-burn engines with a site rating greater than or equal to 250 HP and less than or equal to 500 HP located at a major source) must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines). This facility is a minor source of HAP. EU AN-Emerg. Gen. were constructed prior to June 12, 2006, and is considered an existing stationary emergency source at an area source. Facilities with existing stationary CI RICE located at an area source of HAP emissions must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. Existing emergency stationary RICE at area sources must follow management practices including:

- Change oil and filter every 500 hours of operation or annually, whichever comes first;
- Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and
- Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary

Additionally, there are limitations on the hours of operation for an emergency engine. Total operating hours are limited to 100 hours/year for maintenance and readiness checks. The 100 hours/year includes up to 50 hours of non-emergency operations. The 50 hours cannot include peak shaving or other income generating power production. The 50 hours includes up to 15 hours of power generation as part of a demand response program in the event of a potential electrical blackout situation. Beginning January 1, 2015, the engine must be fueled with a diesel fuel meeting the requirements of 40 CFR § 80.510(b) for nonroad diesel fuel (15 ppmw S).

CAM, 40 CFR Part 64 [Not Applicable]
Compliance Assurance Monitoring (CAM), as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source that is required to obtain a Title V permit, if it meets all of the following criteria:

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY

The simple cycle gas turbines AN-UNIT 7 and AN-UNIT8 use water injection to reduce emissions of NO_X. However, water injection is considered a passive control measure which acts to prevent pollutants from forming and is not considered a control device as defined by this part.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
This facility does not store any regulated substance above the applicable threshold limits. More information on this federal program is available at the web site: *http://www.epa.gov/rmp/.*

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
EUs AN-UNIT 7 and AN-UNIT 8 are subject to acid rain permitting and are currently authorized under Permit No. 2014-1373-ARR3.

Acid Rain, 40 CFR Part 73 (SO_2 Requirements) [Applicable]
This part provides for allocation, tracking, holding, and transferring of SO_2 allowances.

Acid Rain, 40 CFR Part 75 (Monitoring Requirements) [Applicable]
EU AN-UNIT7 and AN-UNIT8 are affected units and must meet the monitoring requirements of the Acid Rain Program whenever these units are operated. AN-UNIT7 and AN-UNIT8 are limited to a total of 8,000 hours per year of operation.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.
Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

Conditions are included in the standard conditions of the permit to address the requirements specified at §82.156 for persons opening appliances for maintenance, service, repair, or disposal; §82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; §82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; §82.166 for recordkeeping; § 82.158 for leak repair requirements; and §82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

Federal NO_X and SO_2 Trading Programs, 40 CFR Part 97 [Subpart EEEEE is Applicable]
Subpart EEEEE, Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 2 Trading Program. This subpart establishes various provisions for the CSAPR NO_X Ozone Season Group 2 Trading Program, under Section 110 of the Clean Air Act and under the Federal Implementation Plan (FIP) codified under 40 CFR § 52.38. Under this subpart, the permittee is required to designate an official representative, monitor emissions, keep records, and make reports in accordance with §§ 97.830 through 97.835. The monitoring program must comply

with 40 CFR Part 75 or an alternative monitoring program must be requested and approved. CSAPR NO_X Ozone Season Group 2 allowances are periodically allocated to the facility and at the completion of the allowance transfer deadline for the control period in a given year the permittee is required to hold, in the source's compliance account administered by the EPA Clean Air Markets Division (CAMD), sufficient allowances available for deduction for such control period under § 97.824(a) in an amount not less than the tons of total NO_X emissions for the control period from all CSAPR NO_X Ozone Season Group 2 units at the facility. The control period starts on May 1 of a calendar year, except as provided in § 97.806(c)(3), and ends on September 30 of the same year. For the CSAPR NO_X Ozone Season Group 2 Trading Program, the deadline for obtaining sufficient allowances is midnight of November 1 (if November 1 is a business day) or midnight of the first business day after November 1 (if November 1 is not a business day). Fines and future allowance deductions will be levied as described in § 97.806 if the permittee holds insufficient allowances at the completion of the allowance transfer deadline. The process of establishing an allowance account and requirements for administrating an account are included in § 97.820. The recording of allowance allocations is described in § 97.821. Submission and recording of allowance transfers is described in §§ 97.822 and 97.823. Compliance with ozone season emissions limitations and assurance provisions are described in §§ 97.824 and 97.825. Extra allowances may be banked (see § 97.826) and these vintage allowances may be used in later years with certain restrictions. These allowances do not constitute a property right. No Title V permit revision is required for any allocation, holding, deduction, or transfer of allowances in accordance with this subpart. AN-UNIT7 and AN-UNIT8 are CSAPR NO_X Ozone Season Group 2 units subject to the requirements of this subpart. The permit includes the requirement to comply with all applicable requirements of this subpart.

SECTION X. COMPLIANCE

Tier Classification

This application has been determined to be Tier II based on the request for modification of a construction permit for a PSD major source.

The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land.

Public Review

The applicant published the "Notice of Filing a Tier II Application" in *The Anadarko Daily News*, a daily newspaper, in Caddo County on February 24, 2018. The notice stated that the application was available for public review at the Anadarko Public Library located at 215 West Broadway Anadarko, Oklahoma and was also available for review at the Air Quality Division main office. The applicant published the "Notice of Tier II Draft Permit" in *The Anadarko Daily News*, a daily newspaper, in Caddo County on May 5, 2018. The notice stated that the draft permit was available for public review at the Anadarko Public Library located at 215 West Broadway Anadarko, Oklahoma and was also available for review at the Air Quality Division main office and on the Air Quality section of the DEQ Web Page: http://www.deq.state.ok.us/. No comments were received from the public.

Information on all permit actions is available for review in the Air Quality section of the DEQ Web page: *http://www.deq.state.ok.us/*.

State Review
This facility is not located within 50 miles of the Oklahoma border.

EPA Review
This permit was approved for concurrent EPA and public review and the draft permit was forwarded to EPA for a 45-day review period. Since no comments were received from the public, the draft permit is deemed the proposed permit. No comments were received from the EPA.

Fees Paid
Part 70 construction permit application fee for modification of an existing facility of $6,000.

SECTION XI. SUMMARY

The facility demonstrated the ability to comply with the applicable air quality rules and regulations. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance or enforcement issues concerning this facility. Issuance of the modified construction permit is recommended.

OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

MARY FALLIN
Governor

JUN 19 2018

Western Farmers Electric Cooperative
Attn: Mr. Gerald Butcher
Environmental Coordinator
701 NE 7th Street
Anadarko, OK 73005-0429

SUBJECT: Permit 2015-1968-C (M-2) PSD
Anadarko Power Plant (Facility ID: 1699)
Location: Section 14-T7N- R10W, Caddo County, Oklahoma

Dear Mr. Butcher:

Enclosed is the modified construction permit of the referenced facility. Please note that this permit is issued subject to the certain standards and specific conditions that are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emissions Inventory Staff at 405-702-4100.

If you have any questions, refer to the permit number above and contact Eric Milligan at eric.milligan@deq.ok.gov or at (405) 702-4217. Thank you for your cooperation.

Sincerely,

Eric L. Milligan, P.E.
Engineering Section
AIR QUALITY DIVISION

Enclosures

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 NORTH ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2015-1968-C (M-2) PSD

Western Farmers Electric Cooperative,

having complied with the requirements of the law, is hereby granted permission to construct/operate the Anadarko Power Plant in the NW/4 of Section 14, T7N, R10W, Caddo County subject to the Standard Conditions dated June 21, 2016, and the Specific Conditions, both of which are attached:

In the absence of construction commencement, the ability to commence construction under this permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.

6-18-18

Division Director **Date**

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Western Farmers Electric Cooperative
Anadarko Power Plant

Permit Number 2015-1968-C (M-2) PSD
Facility ID: 1699

The permittee is authorized to construct/operate in conformity with the specifications submitted to Air Quality on August 24, 2000 (Original PSD Application) and February 2, 2018, and all supplemental materials. The Evaluation Memorandum, dated June 18, 2018, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction and continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Points of emissions and limitations for each point: [OAC 252:100-8-6(a)(1)]

EUG 4 Internal Combustion Engine: EU Emerg. Gen. EU Emerg. Gen shall not be operated more than 100 hours, each, in any 12-month period for maintenance and readiness checks. Use of the engines during emergencies is unlimited. Emissions for EU Emerg. Gen. are considered insignificant.

EU	Make/Model	hp	Serial #	Const. Date
Emerg. Gen	Kohler/600 ROZD-4	910	0655525	2000

a. The owner/operator shall comply with all applicable requirements of the NESHAP: Reciprocating Internal Combustion Engines, Subpart ZZZZ, no later than May 3, 2013, for each affected facility including but not limited to:

<u>What This Subpart Covers</u>

(1) § 63.6580 What is the purpose of subpart ZZZZ?
(2) § 63.6585 Am I subject to this subpart?
(3) § 63.6590 What parts of my plant does this subpart cover?
(4) § 63.6595 When do I have to comply with this subpart?
   (i) If you have an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. [§ 63.6595(a)(1)]

<u>Emission and Operating Limitations</u>

(5) § 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?
   (i) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d of 40 CFR Part 63, Subpart ZZZZ which apply to you. [§ 63.6603(a)]

(A) Change oil and filter every 500 hours of operation or annually, whichever comes first or utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement.
[Table 2d, 40 CFR part 63, Subpart ZZZZ]

(B) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and [Table 2d, 40 CFR part 63, Subpart ZZZZ]

(C) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.
[Table 2d, 40 CFR part 63, Subpart ZZZZ]

(6) § 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(i) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR § 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted. [§ 63.6604(b)]

<u>General Compliance Requirements</u>

(7) § 63.6605 What are my general requirements for complying with this subpart?

(i) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.
[§ 63.6605(a)]

(ii) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [§ 63.6604(b)]

<u>Testing and Initial Compliance Requirements</u>

(8) § 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

(i) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 of Subpart ZZZZ that apply to you within 180 days after the compliance date that is specified for your stationary RICE in § 63.6595 and according to the provisions in § 63.7(a)(2).[§ 63.6612(a)]

(9) § 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(i) You must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [§ 63.6625(e)(2)]

(ii) If you own or operate an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed. [§ 63.6625(f)]

(iii) If you operate an existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 2d of Subpart ZZZZ apply. [§ 63.6625(h)]

(iv) You have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Table 2d of 40 CFR Part 63, Subpart ZZZZ. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2d of 40 CFR Part 63, Subpart ZZZZ. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine. [§ 63.6625(i)]

(10) § 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(i) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of Subpart ZZZZ. [§ 63.6630(a)]

<u>Continuous Compliance Requirements</u>

(11) § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(12) § 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(i) You must demonstrate continuous compliance with each emission limitation and operating limitation in Table 2d of 40 CFR Part 63, Subpart ZZZZ that apply to you according to methods specified in Table 6 of 40 CFR Part 63, Subpart ZZZZ. [§ 63.6640(a)]

(ii) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE. [§ 63.6640(b)]

(iii) You must also report each instance in which you did not meet the requirements in Table 8 of Subpart ZZZZ that apply to you. [§ 63.6640(e)]

(iv) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in § 63.6640(f)(1) through (4). Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in § 63.6640(f)(1) through (4), is prohibited. If you do not operate the engine according to the requirements in § 63.6640(f)(1) through (4), the engine will not be considered an emergency engine under Subpart ZZZZ and will need to meet all requirements for non-emergency engines. [§ 63.6640(f)]

(A) There is no time limit on the use of emergency stationary RICE in emergency situations. [§ 63.6640(f)(1)]

(B) You may operate your emergency stationary RICE for any combination of the purposes specified in § 63.6640(f)(2)(i) through (iii) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by § 63.6640(f)(3) and (4) counts as part of the 100 hours per calendar year allowed by § 63.6640(f)(2). [§ 63.6640(f)(2)]

(C) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in § 63.6640(f)(2). Except as provided in § 63.6640(f)(4)(i) and (ii), the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity. [§ 63.6640(f)(4)]

<u>Notifications, Reports, and Records</u>

(13) § 63.6645 What notifications must I submit and when?

(i) For each initial compliance demonstration required in Table 5 of Subpart ZZZZ that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration. [§ 63.6645(h)(1)]

(14) § 63.6650 What reports must I submit and when?

(i) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must submit an annual report according to the requirements in § 63.6650(h)(1) through (3). [§ 63.6650(h)]

(15) § 63.6655 What records must I keep?

(i) You must keep the records required in Table 6 of 40 CFR Part 63, Subpart ZZZZ to show continuous compliance with each emission or operating limitation that applies to you. [§ 63.6655(d)]

(ii) if you own or operate an existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d of 40 CFR Part 63, Subpart ZZZZ, you must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan. [§ 63.6655(e)(3)]

(iii) If you own or operate an existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response. [§ 63.6655(f)(2)]

(16) § 63.6660 In what form and how long must I keep my records?

(i) Your records must be in a form suitable and readily available for expeditious review according to § 63.10(b)(1). [§ 63.6660(a)]

(ii) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [§ 63.6660(b)]

(iii) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). [§ 63.6660(c)]

<u>Other Requirements and Information</u>

(17) § 63.6665 What parts of the General Provisions apply to me?

(i) Table 8 of 40 CFR Part 63, Subpart ZZZZ shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. [§ 63.6665(a)]

(18) § 63.6670 Who implements and enforces this subpart?

(19) § 63.6675 What definitions apply to this subpart?

EUG 6 **Turbines:** Emissions limitations for emission units (EU) AN-UNIT7 and AN-UNIT8.

Combustion Turbines (AN-UNIT7 & AN-UNIT8)

Pollutant	lb/hr[3]	TPY[1]	lb/MMBTU
NO_X	41.0[2]	159.3	0.20[2]
CO	122.5	91.0	N/A
PM_{10}	3.0	12.0	N/A
VOC	2.1	1.2	N/A
SO_2	1.56	6.2	N/A

(1) 12-month rolling totals. These limits apply to the combined emissions from both units.
(2) Three hour rolling average.
(3) The lb/hr emission limits apply to each turbine.

a. The permittee shall be authorized to operate the turbines (AN-UNIT7 and AN-UNIT8) up to a total of 8,000 hours in any rolling 12-month period (monthly rolling total). [OAC 252:100-8-6(a)]

b. AN-UNIT7 and AN-UNIT8 shall only be fired with commercial-grade natural gas containing less than 2 grains/100 SCF. [OAC 252:100-31]

c. Emissions from EU AN-UNIT7 and AN-UNIT8 shall be controlled by water injection, which shall be properly operated and maintained to satisfy BACT requirements (25 ppmvd NO_X @ 15% O_2, annual rolling average). [OAC 252:100-8-34(b)]

d. The turbines are subject to the NSPS for Stationary Combustion Turbines 40 CFR Part 60, Subpart GG and shall comply with all applicable requirements including but not limited to the following: [40 CFR § 60.330 to § 60.4420]

  (1) § 60.330 Applicability and designation of affected facility.

  (2) § 60.331 Definitions.

  (3) § 60.332 Standard for nitrogen oxides.

    (i) The owner or operator shall not cause to be discharged to the atmosphere from any stationary gas turbine, except as provided in § 60.332(f), any gases which contain nitrogen oxides in excess of:

      (A) 75 ppmdv (14.4/Y) @ 15% O_2; where Y is the manufacturer's or actual rated heat rate (LHV) at peak load. [§ 60.332(a)(1) & (b)]

    (ii) Stationary gas turbines using water or steam injection for control of NO_X emissions are exempt from § 60.332(a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine. [§ 60.332(f)]

  (4) § 60.333 Standard for sulfur dioxide.

    (i) The owner or operator shall not burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw). [§ 60.333(b)]

  (5) § 60.334 Monitoring of operations.

    (i) The owner or operator of any stationary gas turbine subject to NSPS, Subpart GG and using water or steam injection to control NO_X emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine. [§ 60.334(a)]

(ii) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous monitoring system described in § 60. 334(a), install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15% O_2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F-14a or F-14b in Appendix F to 40 CFR Part 75 and making the adjustments to 15% O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as required by § 60.334(b)(1-3). [§ 60.334(b)]

(iii) For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in § 75.19 or the NO_X emission measurement methodology in appendix E to 40 CFR Part 75, the owner or operator may meet the requirements of § 60.334(g) by developing and keeping on-site a quality-assurance plan, as described in § 75.19 (e)(5) or in Section 2.3 of Appendix E and Section 1.3.6 of Appendix B to 40 CFR Part 75. [§ 60.334(g)]

(iv) The owner or operator of any stationary gas turbine shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in § 60.334 (h)(3). [§ 60.334(h)(1)]

(A) The owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated per § 60.334(h)(3)(i-ii) to meet the definition of natural gas in § 60.331(u). [§ 60.334(h)(3)]

(v) The frequency of determining the sulfur content of the fuel shall be as follows: [§ 60.334(i)]

(A) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in Section 2.3.6 of Appendix D to 40 CFR Part 75 to determine a custom sulfur sampling schedule according to § 60.334(h)(3)(ii)(A-D). [§ 60.334(i)(3)(ii)]

(vi) For each affected unit that elects to continuously monitor emissions, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under § 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined in § 60.334(j)(1-3). [§ 60.334(j)]

(6) § 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in §60.8, using one of the methods in § 60.335(a)(1-3). [§ 60.335(a)]

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8.

2. The permittee shall be authorized to operate this facility continuously (24 hours per day, every day of the year) except as provided above. [OAC 252:100-8-6(a)(1)]

3. The permittee shall not emit 10 TPY or more of formaldehyde (H_2CO) based on a 12-month rolling total. Every month the facility shall calculate and determine compliance with the H_2CO emission limit. [OAC 252:100-8-6(a)(1)]

4. Compliance with the emission limitations specified in Specific Condition No. 1 shall be demonstrated based on performance testing, CEMs data, Part 75 monitoring procedures, or use of applicable emission factors referenced in the Permit Memorandum associated with this permit.

5. Each emission unit at the facility (EUs AN-UNIT7, AN-UNIT8, and Emerg. Gen) shall have a permanent identification plate attached which shows the make, model number, and serial number. [OAC 252:100-43]

6. When operational data of the combined cycle or simple cycle gas turbines shows concentrations in excess of the established emission limits (in excess of lb/hr and lb/MMBTU), the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions. [OAC 252:100-9]

7. The facility is subject to the Acid Rain Program and shall comply with all applicable requirements including the following: [40 CFR Parts 72, 73, & 75]

a. SO_2 actual emissions shall be equal to or less than allowances held.
b. Report quarterly emissions to EPA per 40 CFR 75.
c. Maintain a QA/QC plan for maintenance of the monitoring system.

8. Emission Units AN-UNIT7 and AN-UNIT8 are subject to the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 2 Trading Program. The permittee shall comply with all applicable requirements including but not limited to: [40 CFR § 97.801 to § 97.835]

a. § 97.801 Purpose.
b. § 97.802 Definitions.
c. § 97.803 Measurements, abbreviations, and acronyms.
d. § 97.804 Applicability.
e. § 97.805 Retired unit exemption.
f. § 97.806 Standard requirements.
g. § 97.807 Computation of time.
h. § 97.808 Administrative appeal procedures.
i. § 97.810 State NO_X Ozone Season Group 2 trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.
j. § 97.811 Timing requirements for CSAPR NO_X Ozone Season Group 2 allowance allocations.
k. § 97.812 CSAPR NO_X Ozone Season Group 2 allowance allocations to new units.
l. § 97.813 Authorization of designated representative and alternate designated representative.

m. § 97.814 Responsibilities of designated representative and alternate designated representative.
n. § 97.815 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.
o. § 97.816 Certificate of representation.
p. § 97.817 Objections concerning designated representative and alternate designated representative.
q. § 97.818 Delegation by designated representative and alternate designated representative.
r. § 97.820 Establishment of compliance accounts, assurance accounts, and general accounts.
s. § 97.821 Recordation of CSAPR NO_X Ozone Season Group 2 allowance allocations and auction results.
t. § 97.822 Submission of CSAPR NO_X Ozone Season Group 2 allowance transfers.
u. § 97.823 Recordation of CSAPR NO_X Ozone Season Group 2 allowance transfers.
v. § 97.824 Compliance with CSAPR NO_X Ozone Season Group 2 emissions limitation.
w. § 97.825 Compliance with CSAPR NO_X Ozone Season Group 2 assurance provisions.
x. § 97.826 Banking.
y. § 97.827 Account error.
z. § 97.828 Administrator's action on submissions.
aa. § 97.830 General monitoring, recordkeeping, and reporting requirements.
bb. § 97.831 Initial monitoring system certification and recertification procedures.
cc. § 97.832 Monitoring system out-of-control periods.
dd. § 97.833 Notifications concerning monitoring.
ee. § 97.834 Recordkeeping and reporting.
ff. § 97.835 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

9. Replacement (including temporary periods of 6 months or less for maintenance purposes), of the internal combustion engines/turbines with emissions specified in this permit with engines/turbines of lesser or equal emissions of each pollutant (in lb/hr and TPY) are authorized under the following conditions.

a. The permittee shall notify AQD in writing not later than 7 days in advance of start-up of the replacement engine(s)/turbine(s). Said notice shall identify the old engine/turbine and shall include the new engine/turbine make and model, serial number, horsepower rating, fuel usage, stack flow (ACFM), stack temperature (°F), stack height (feet), stack diameter (inches), and pollutant emission rates (g/hp-hr, lb/hr, and TPY) at maximum horsepower for the altitude/location.
b. Emissions tests for the replacement turbine(s) shall be conducted to confirm continued compliance with NO_X and CO emissions limitations. A copy of the initial testing shall be provided to AQD within 60 days of start-up of each replacement turbine. The test report shall include the engine/turbine fuel usage, stack flow (ACFM), stack temperature (°F), stack height (feet), stack diameter (inches), and pollutant emission rates (lb/hr, and TPY) at maximum rated horsepower for the altitude/location.
c. Replacement equipment and emissions are limited to equipment and emissions which are not a modification under NSPS or NESHAP, or a significant modification under PSD. For existing PSD facilities, the permittee shall calculate the PTE or the net emissions increase

resulting from the replacement to document that it does not exceed significance levels and submit the results with the notice required by a. of this Specific Condition.

d. Engines installed as allowed under the replacement allowances in this Specific Condition that are subject to 40 CFR Part 63, Subpart ZZZZ and/or 40 CFR Part 60, Subparts GG, IIII, JJJJ, or KKKK shall comply with all applicable requirements.

[OAC 252:100-8-6(a) & OAC 252:100-8-6 (f)(2)]

10. The following records shall be maintained on-site to verify Insignificant Activities. No recordkeeping is required for those operations which qualify as Trivial Activities.

[OAC 252:100-8-6 (a)(3)(B)]

a. For activities (except for trivial activities) that have the potential to emit less than 5.0 TPY (actual) of any criteria pollutant: The type of activity and the amount of emissions or a surrogate measure of the activity (annual).

11. The permittee shall maintain records of operations as listed below. These records shall be maintained on-site for at least five years after the date of recording and shall be provided to regulatory personnel upon request. [OAC 252:100-8-6 (a)(3)(B)]

a. Total natural gas usage for each simple cycle gas turbine (monthly).
b. Operating hours for EU AN-UNIT7, AN-UNIT8, and Emerg. Gen (monthly 12-month rolling totals).
c. Records required by NSPS, Subpart GG.
d. Records required by NESHAP, Subpart ZZZZ.
e. Records required by the Acid Rain Program.
f. Calculations documenting compliance with the H_2CO emission limit (monthly 12-month rolling totals).
g. Sulfur content of natural gas (using either the gas quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract, using representative fuel sampling data per 40 CFR Part 75 Appendix D, current lab analysis, stain-tube analysis, or other approved method). Compliance shall be demonstrated at least once every calendar year.
h. Records required by 40 CFR Part 97, Subpart EEEEE.
i. Records of periodic testing required by Specific Condition 9.
j. Records of required notices, testing, and compliance required by Specific Condition 10.

12. This permit supersedes Permit No. 2000-273-C (PSD) for this facility, which is now cancelled.

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(June 21, 2016)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.

[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.

[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.

[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking,

reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.
[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.
[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.
[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.
[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.
[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(17) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.
[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.
[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]
(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

    (a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
    (b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
    (c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
    (d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of

adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;

(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and

(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;

(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;

(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;

(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;

(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and

(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.

(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).

(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).

(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).

(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.

(6) The DEQ complies with 40 C.F.R. § 70.8(d).

(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).

(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.

(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]